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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 150001-EI ORDER NO. PSC-15-0586-FOF-EI ISSUED: December 23, 2015

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
JULIE I. BROWN
JIMMY PATRONIS

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

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BY THE COMMISSION:

Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive factor clause proceedings, an administrative hearing was held on November 2-3, 2015. At the hearing, we approved, with modifications, certain stipulated issues for Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Power & Light Company (FPL), Florida Public Utilities Company (FPUC), and Duke Energy Florida, LLC. (DEF) by bench decision. These stipulations, as modified, are found in Attachment A. Although we approved some stipulated issues for each of these investor-owned utilities (IOUs), testimony and other evidence was presented at the November 2-3, 2015 hearing on hedging-related issues for the generating IOUs, and also for company-specific issues for FPUC. TECO, Gulf, FPL, FPUC, DEF, Florida Industrial Power Users Group (FIPUG), the Office of Public Counsel (OPC), and PCS Phosphate (PCS) filed briefs on November 13, 2015.[1]

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

Hedging

Our analysis of this issue will begin by providing a background on how our policy on hedging has been developed and the key actions we have taken regarding the hedging programs that Florida's four largest IOUs use today.

Background

Hedging allows utilities to manage the risk of volatile swings in the price of fuel. Prior to 2001, IOUs had carried out a small number of financial hedging transactions. In response to significant fluctuations in the price of natural gas and fuel oil during 2000 and 2001, this Commission raised issues regarding the utilities' management of fuel price risk as part of the 2001 fuel clause proceeding. The specific issues raised involved the reasonableness of hedging as a tool to manage fuel price risk and the appropriate regulatory treatment of hedging gains and losses. These issues were spun off to Docket No. 011605-EI for further investigation.

At the hearing for Docket No. 011605-EI, parties reached a settlement of all issues. By Order No. PSC-02-1484-FOF-EI ("Hedging Order"),[2] we approved the settlement of the issues. Specifically, the settlement provided a framework that incorporated hedging activities into fuel procurement activities. For natural gas, fuel oil, and purchased power, the settlement allowed Florida's generating IOUs to charge prudently incurred hedging gains and losses to the fuel clause. The Hedging Order specified that this Commission will review each IOU's hedging activities as part of the annual fuel proceeding.

The Hedging Order required utilities to file risk management plans as part of true-up filings. The intent of this requirement was to allow this Commission and parties to the fuel docket to monitor utility hedging activities. As part of the annual final true-up filings in the fuel docket, utilities were required to state the volumes of fuel hedged, the type of hedging instruments, the average length of the term of the hedge positions, and fees associated with hedging transactions.

Although the Hedging Order allowed utilities flexibility in the development of risk management plans, the order also set forth guidelines utilities were to follow. For example, the order required that risk management plans identify the objectives of the hedging programs and the minimum quantities to be hedged. The order also required that plans provide mechanisms and controls for the proper oversight within the utility of hedging activities, as well as include the method for assessing and monitoring fuel price risk.

In tandem with Docket No. 011605-EI, Commission staff conducted a review of Internal Controls of Florida's Investor-Owned Utilities for Fuel and Wholesale Energy Transactions.

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[1] The Florida Retail Federation (FRF) filed a notice of joinder in OPC's brief on the same date.
[2] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management policies and procedures.

This study examined the practices, procedures, controls, and policies these companies followed when purchasing fossil fuels and wholesale energy. The study period looked at data from 1998 through 2001. The study concluded that Florida IOUs had engaged in physical hedging in fuel procurement but very limited financial hedging. At the time, the IOUs had not set up the proper controls to engage in extensive financial hedging. Also, for the period studied, TECO and Gulf had little exposure to the volatility of natural gas prices.

The next time we reviewed our policy on hedging was at the 2007 fuel hearing. Parties raised questions regarding the period for which we were determining the prudent costs of hedging activities. We deferred our decision on the prudence of 2007 hedging activity costs to 2008 in order to allow for sufficient development of data and review of the matter.

Following the 2007 fuel hearing, two audits of the IOU's hedging programs were conducted by Commission staff. First, staff conducted a management audit reviewing the IOUs' hedging programs to assess the costs and benefits realized since the entry of the Hedging Order. Also reviewed was the IOUs' accounting treatment of 2007 hedging activities to determine compliance with their risk management plans filed in 2006.

The management audit assessed the current and historical strategies of the fuel procurement hedging programs within each company at that time, evaluated hedging objectives set forth in each company's risk management plan, and quantified the net costs and benefits of each company's hedging program. Specifically, the structure and performance of hedging natural gas and fuel oil through the use of physical purchases and/or financial instruments for the years 2003 through 2007 was examined. Information was collected regarding each company's policies and procedures, organizational charts, risk management plans, and historical hedging transactions, and an analysis conducted for each company. In June 2008, a report was issued entitled Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities.

In its 2008 report, Commission staff found that each company shared a universal goal in purchasing financial hedges for its fuel procurement; that is, to reduce the impacts of the price extremes that can occur in the natural gas and fuel markets. In their hedging activities, the companies were not attempting to speculate on price movements in the market. Rather each was working to stabilize its annual fuel costs by initializing and settling financial hedging transactions through authorized financial counterparties. The volumes of gas and fuel oil hedged were less than the total volumes expected to be purchased. Overall, staff believed that the use of financial hedges for fuel purchases provided a benefit to utility customers.

In response to the deferral of the determination of the prudent costs in the 2007 fuel hearing, on January 31, 2008, FPL filed a petition requesting that we approve FPL's proposed volatility mitigation mechanism (VMM) as an alternative to FPL's hedging program. The VMM proposal involved FPL collecting under recoveries of fuel costs over two years instead of one year, as is the current practice. On March 11, 2008, a workshop was held to get stakeholder input on this proposal. All parties to the 2002 settlement attended.

By Order No. PSC-08-0316-PAA-EI,[3] we clarified the Hedging Order in several areas. IOUs were required to file a Hedging Information Report by August 15th of each year. We also

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[3]Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.

specified that it would make a determination of prudence of hedging results for the twelve month period ending July 31st of the current year. Additional workshops were held on June 9, 2008, and June 24, 2008, regarding FPL's VMM petition and guidelines for hedging programs. FPL withdrew its VMM petition on August 5, 2008.

Following the workshops, we established guidelines for risk management plans by Order No. PSC-08-0667-PAA-EI.[4] At that time we determined that utility hedging programs provide benefits to customers. The guidelines clarified the timing and content of regulatory filings for hedging activities, but allowed the IOUs flexibility in creating and implementing risk management plans. Each year in the fuel clause, our auditors review utility hedging results for the twelve month period ending July 31 of the current year. In addition, each year we approve the IOUs' risk management plans for hedging transactions the utility will enter the following year and beyond.

No other hedging-related orders have been issued to date, although on several occasions since the issuance of these three orders, Commission staff has presented hedging-related information to us at our publically noticed Internal Affairs meetings.

Since the 1990s, natural gas-fired generation has become a large part of the generation mix for Florida IOUs, and the increasing role for natural gas is expected to continue. Natural gas prices have been volatile over the years, with significant price spikes in 2000, 2003, 2005, and 2008. Since 2008, natural gas supply has increased significantly due to shale gas production.

Analysis

This issue focuses on three somewhat overlapping arguments: (1) the significant opportunity costs of hedging programs that IOUs incurred as part of fuel costs paid by customers; (2) whether the volatility of natural gas prices has declined to the point where hedging is no longer effective or necessary; and (3) whether conditions in the natural gas market are stable and eliminate the need for hedging.

The intervenors have argued in their briefs, supported by testimony of record, that hedging should be discontinued due to the large cumulative actual and projected net losses for each IOU from 2002 until 2015. The IOUs counter in their testimony and briefs that the purpose of hedging, as recognized in our previous hedging orders, is to reduce price volatility. While gains and losses can occur, the IOUs contend that assessing the merits of retaining hedging programs based on resultant gains or losses simply encourages price speculation, a practice that neither party believes to be in the ratepayers' best interests.

IOU witnesses acknowledged that there have been significant net cumulative hedging losses for natural gas. FPL had losses of $3.5 billion for the period 2002 to 2014 for natural gas ($3.162 billion when fuel oil hedging gains are included) and projects hedging losses of $490 million for 2015. DEF incurred $1.2 billion in losses for the period 2002 to 2014 and estimates $196 million in losses for 2015. Gulf Power incurred $127 million in losses from 2002 to 2014 and estimates $44 million for 2015. Tampa Electric incurred losses of $381 million for the

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[4]Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.

period 2002 to 2014 and estimates $40 million for 2015. FPL's recently approved Woodford project is also estimated to experience hedging losses for 2015. OPC witness Lawton testified that this prolonged period of losses should signal a re-evaluation of the necessity for hedging programs. However, there were earlier periods before 2008 when gains did offset losses. Customers have consistently benefited from falling prices for the unhedged portion of the IOUs' gas supply portfolios which fluctuates year to year based upon each IOU's approved Risk Management Plan. Each IOU witness testified that the goal of its hedging program was to reduce price volatility and that our previously approved hedging guidelines and procedures provide reasonable tradeoffs for mitigating volatility.

We agree that the level of opportunity savings and costs – hedging gains and losses – should not be a chief consideration in deciding whether to continue fuel price hedging. When gas prices are falling, losses will occur. Conversely, when gas prices are rising, gains will occur. The main objective of IOU hedging programs is to reduce the customer's exposure to fuel price volatility, not to reduce fuel costs. Therefore, these programs should be well disciplined to accomplish this objective and to be non-speculative.

As emphasized by intervenors, the cumulative losses are currently large. These losses are the result of steadily falling natural gas prices in the open market. Customers continue to experience the benefits of the current downward trend in prices for the unhedged portions of the IOUs' natural gas purchases. Should the market price of natural gas trend or spike upward, hedging savings will occur but, overall, fuel costs will increase.

OPC witness Lawton testified that since price volatility has decreased and is trending downward, hedging is unnecessary. IOU witnesses both agreed and disagreed that price volatility had decreased since 2001. DEF witness McAllister agreed with witness Lawton that natural gas prices are less volatile. Gulf witness Ball stated that Gulf does not forecast price volatility and suggests such a forecast is not possible. However, witness Ball also testified that, with a few exceptions, in recent history price volatility has been lower. TECO witness Caldwell agreed that fuel price volatility decreased during the period 1997 to 2015.

FPL witness Yupp strongly disagreed with OPC's conclusion. While the price of natural gas has trended downward over the last several years, and the trend line in natural gas volatility has done the same, witness Yupp testified that the volatility of natural gas prices has varied considerably year to year. Thus, while the trend line for natural gas volatility shows a decline, there is a very low correlation of the trend line with the yearly data. That being the case, the trend line in price volatility is not a statistically valid predictor of next year's price volatility point. Based on this analysis, witness Yupp concluded that one cannot reasonably conclude that natural gas price volatility has decreased as natural gas prices have fallen or will decrease in the future. Witness Yupp testified that hedging had been successful in reducing price volatility as measured by the fact that FPL only met the plus or minus ten percent mid-course correction threshold established by Rule 25-6.0424, F.A.C., once for the period 2002 to 2014 with hedging. Had FPL not hedged, this threshold would have been exceeded nine times. Witness Yupp also testified that the current EIA forecasts for natural gas prices show a confidence interval of ranging more toward higher prices than lower prices. Gulf witness Ball affirmed this aspect of the EIA forecast and OPC witness Lawton acknowledged this fact. The confidence intervals for natural gas prices included in EIA's forecast are consistent with the economic reality that gas prices cannot indefinitely continue to decrease as the price of any commodity cannot fall below the price of production for sustained periods of time.

OPC has argued that the annual fuel factor smoothes out price volatility and is a cost-free alternative to hedging. Witness Lawton stated that the annual or level fuel factor effectively shields customers from day-to-day changes in market prices. However, witness Lawton acknowledges that the cumulative effect of unexpected changes in market prices could lead to a mid-course correction to fuel factors. DEF witness McCallister agreed that the level fuel factor can reduce the customer's exposure to price volatility within any given year, assuming no mid-course correction. However, without hedging true-up amounts in subsequent years could be significant. TECO witness Caldwell testified that while the annual fuel factor provides some smoothing over a twelve month period, it does not limit the potential for fuel costs to increase or decrease, i.e., fuel price volatility. Witness Caldwell also testified that spreading an under-recovery over more time, as suggested by FPL in 2008 by its validation mitigation mechanism (VMM), without hedging any portion of the natural gas portfolio presents a risk of stacking under-recoveries if prices rise making the rate impact on ratepayers even greater.

The record is clear that setting a level or annual factor has some smoothing effect within any given year assuming no mid-course corrections. The record is also clear that by providing certainty to a portion of expected gas consumption, hedging reduces annual true-up amounts and the number of mid-course corrections required by our rules.

A review of the testimony reveals that both intervenor and IOU witnesses generally agree that price volatility cannot be accurately or consistently forecasted. The record before us indicates that from 2002 to date natural gas price volatility has varied up and down significantly, with 2009 and 2014 reaching levels of 99.6 percent and 96.7 percent, respectively. Therefore, while natural gas prices have trended downward in the last few years, the level of price volatility cannot be predicted with any certainty. It is important to remember that the impact on ratepayers of even small variations in the price of natural gas is significant, e.g., a one cent change in natural gas prices results in $6 million in additional fuel expense for FPL's customers. The increased dependence on natural gas for each of Florida's IOUs means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued.

As stated in our past decisions, the objective of the IOUs' hedging programs is to reduce the customers' exposure to price volatility. Currently, natural gas prices are low compared to prices since 2008. One could reasonably assume that prices are more likely to rise than to continue downward, and FPL witness Yupp provides calculations, reasons, and an opinion supporting this possibility. That prices may be approaching or going below the variable cost of production is a noteworthy consideration. However, the low prices and possible price direction should not be a chief consideration since it would necessarily involve some degree of speculation about the future direction of prices.

Intertwined with price volatility are the supply and demand conditions of the natural gas market. All witnesses agreed that natural gas market conditions in 2015 are different from those of 2002. All witnesses agreed that the growth of shale gas production has increased the supply of natural gas. TECO witness Caldwell noted that the natural gas market seems to move in cycles of significant production increases, due to new sources, followed by increases in demand

Natural gas prices are more volatile when weather events affect supply or demand. In January 2014, the polar vortex had a significant effect on natural gas prices. Weather events, such as very cold periods during the winter, can increase demand, prices, and volatility. However, additional pipelines under construction that connect the Marcellus Shale to northeastern states may diminish this effect.

Regarding shale gas production and the current abundant supply of natural gas, FPL witness Yupp noted that the market price may be below the cost of production for many producers. The market price cannot be below the cost of production for any extended period of time. He further noted that production costs vary among producers. Rig counts are down and this could impact gas supply, but this too may not be a complete indicator of future gas production.

Gulf witness Ball alluded to future events that could disrupt shale gas production, e.g., existing or proposed local, state, or federal environmental regulations either banning or restricting shale gas production, or increased demand for natural gas based upon federal power plant regulations reducing carbon emissions. He testified that OPC has minimized any potential threats to shale gas production. However, while opining that environmental concerns have largely been put to rest, OPC witness Lawton acknowledged that New York currently bans hydraulic fracking.

Demand for natural gas, particularly for electric generation, for both Florida and the country as a whole is increasing. In 2016, DEF, FPL, TECO and Gulf estimate 73, 72, 52 and 44 percent of their generation, respectively, will be from natural gas. In addition, natural gas will begin to be exported in late 2015, and a number of export terminals are under construction or are planned.

The decision of whether to continue fuel price hedging turns on what one expects price volatility and natural gas market conditions to do in the future. While natural gas prices have trended down, price volatility is uncertain and cannot be reliably forecasted. What this record clearly establishes is that without hedging, customers have a very significant exposure to natural gas price volatility due to a very dynamic natural gas market. Today natural gas prices are low and gas supply is forecasted to be abundant. However, demand for natural gas is increasing and is heavily influenced by weather and uncertain supply conditions. Given these factors, on balance we find that the continuation of natural gas hedging process as outlined in our previous orders is in the customers' best interests.

Our decision to continue hedging at this time is based on the evidence presented in this record which in large part consists of arguments to either completely eliminate hedging or to continue the procedures in place at this time. There was no written testimony from any party and very limited cross examination on possible changes to the manner in which the IOUs conduct natural gas financial hedging activities or alternatives to hedging: cost sharing of hedging gains and losses between the IOUs and ratepayers, alternative accounting treatment for recovery of gains and losses (VMM program), or imposing limits on the percentage of natural gas purchases hedged. All witnesses agreed that any changes to the hedging protocol should be prospective and that the current hedges should be allowed to terminate on their original contract dates. Notwithstanding our decision on hedging, we recognize that the cost of this program is significant by any measure for each Florida IOU and deserves further analysis. Therefore, we direct our staff, in conjunction with the parties to this docket, to explore possible changes to the current hedging protocol that will minimize potential losses to customers.

Risk Management Plans

Consistent with our decision above, we find that the 2016 Risk Management Plans of DEF, FPL, TECO and Gulf shall be approved. Each plan provides the appropriate governance for a well-disciplined and prudently managed utility hedging program and is consistent with the Hedging Guidelines. These plans are structured to reduce price volatility risk in a structured manner and with the exception of FPL's plan, which includes participation in the Woodford Gas Reserves Project, is very similar to risk management plans approved in past years.

Company-Specific Fuel Adjustment Issues

Florida Power & Light Company

Woodford Gas Reserve Project

On June 25, 2014, FPL petitioned the Commission for a determination that it was prudent for FPL to acquire an interest in a natural gas reserve project (the Woodford Project) and that the revenue requirement associated with investing in and operating the gas reserve project was eligible for recovery through the Fuel Clause. In Order No. PSC-15-0038-FOF-EI[5] (Woodford Order), the Commission found that the Woodford Project was in the public interest and its costs were recoverable through the Fuel Clause. OPC and FIPUG have filed appeals of the Woodford Order with the Florida Supreme Court, which are pending as of the date of this order[6].

As summarized in the Woodford Order, the Woodford Project is a capital investment by which FPL invests directly in shale gas reserves in the Woodford Shale region of Oklahoma and ratepayers pay natural gas production costs rather than the market price on the physical gas produced.

[5] Order No. PSC-15-0038-FOF-EI, issued January 12, 2015, in Docket No. 150001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

[6] On March 30, 2015, the Florida Supreme Court consolidated OPC's three appeals and the FIPUG appeal into a single case (Florida Supreme Court Case No. SC15-95).

> Historically, production costs have been less volatile than market prices. We find the Woodford Project will act as a hedge that is designed to decouple costs from market prices.[7] The Woodford Project costs are based solely on the operations and maintenance costs, and on the investment that is required, and is essentially fixed. FPL purchases more natural gas than any other electric utility in the country. The reality is that in this state, and nationally, we continue to grow the need for natural gas to provide electricity as we move away from coal. Although the Woodford Project is relatively small and will have a small effect on FPL's overall cost of natural gas and on price hedging, it will act as a long-term physical hedge (30 years or longer in duration) compared to financial hedges, which typically lock in prices for 12 – 24 months. Fuel and related costs that are subject to volatile changes are recoverable through the Fuel Clause.[8] We have allowed non-fuel items to be recovered through the Fuel Clause as long as they are projected to result in fuel savings.[9] FPL's natural gas price forecasts of October 2013 and July 2014 indicate that the Woodford Project will likely produce positive customer fuel savings over the life of the Project based on combinations of two factors: well productivity and natural gas market price. Under FPL's July 2014 natural gas price forecast, 6 of 9 sensitivities produce positive customer savings. ...

Order No. PSC-15-0038-FOF-EI at pp. 4-5.

The Woodford Project order is presently on appeal at the Florida Supreme Court. However, no motions to stay have been filed and the Woodford Order remains in full force and effect. Further, FPL has moved forward with its investment, and drilling and production activity began earlier this year. Therefore, we find that FPL is entitled to recover its Woodford Project costs through the Fuel Clause in the amount of $24,611,461 for the period January 2015 through December 2015. For the period January 2016 through December 2016, we find that the appropriate projected costs FPL shall be allowed to recover through the Fuel Clause for the Woodford natural gas exploration and production project is $53,777,690.

Florida Public Utilities Company

FPL Interconnection and legal and consultant fees

FPUC has requested that it be allowed to recover $107,333 in 2016, representing the depreciation expense, taxes other than income taxes and a return on investment associated with the $3.5 million dollar cost of rerouting FPUC's 138 KV transmission line to parallel an existing

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[7]Customers currently bear certain drilling, production, and shale gas risks (earthquakes, environmental issues, etc.) as these factors are embedded in the market price of gas.
[8]Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, In re: Cost recovery Methods for Fuel-Related Expenses.
[9]Order Nos. PSC-97-0359-FOF-EI, issued March 31, 1997, in Docket 970001-EI, In re: Fuel and purchased power cost recovery clause and generating performance incentive factor (FPL investment in rail cars) and PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket 010001-EI, In re: Fuel and purchased power cost recovery clause and generating performance incentive factor (Incremental Power Plant Security Costs).

FPL 230 KV line and upgrading FPL's substation to accommodate this interconnection. At this time, FPUC's 138 KV transmission is directly connected to the JEA 138 KV transmission network. If construction is started in 2016, the completion date is expected during the latter half of 2017. FPUC has estimated that savings will result from this interconnection for essentially two reasons: 1) improved system reliability on FPUC's transmission system; and 2) the ability to purchase power from other wholesale providers without incurring additional transmission wheeling costs which should result in lower purchased power costs. FPL will be constructing the transmission line with the costs to be reimbursed by FPUC.

FPUC does not generate any electricity but is solely dependent on wholesale purchase power agreements to meet its capacity and energy needs. At this time, FPUC has wholesale power purchase agreements with JEA which serve its Northeast Division (Amelia Island) and Gulf Power Company (Gulf) which serve its Northwest Division (Marianna). Both of these wholesale purchased power contracts include payments for JEA's and Gulf's transmission rate base costs to provide power to FPUC. However, FPUC does not currently recover any of its own transmission rate base costs through the fuel clause. FPUC's current contract with JEA is set to expire on December 31, 2017, the same time that FPUC's interconnection with FPL is expected to be completed. FPUC is required to purchase all of its wholesale purchased power from JEA during the term of the current contract. Thus, the projected $2.3 million in savings for future purchased power costs associated with the FPL interconnection cannot materialize until after January 1, 2018.

FPUC intends to issue a request for proposals (RFP) soliciting capacity and energy for delivery beginning in 2018. FPUC anticipates that as a result of its RFP it will be able to contract for wholesale capacity and energy at significantly lower rates once the FPL interconnection is completed.

Our basic guidelines for recovery of capital costs through the fuel adjustment clause are found in Order No. 14546.[10] Since the issuance of Order No. 14546 in 1985, we have issued 19 orders interpreting and applying these two principles to various proposed rate base capital costs for which recovery through the fuel clause was requested.[11] FPUC's arguments focus on why its proposed transmission project qualifies for recovery through the fuel adjustment clause.

However, OPC, FRF, FIPUG, and PCS all take the position that the rate case stipulation and settlement agreement entered into between OPC and FPUC on August 29, 2014 and

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[10]Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI,-B, In re: Cost Recovery Methods for Fuel-Related Expenses.

[11]Order No. PSC-11-0080-PAA-EI, issued on January 31, 2011, in Docket No. 100404-EI, In re: Petition by Florida Power & Light Company to recover Scherer Unit 4 Turbine Upgrade costs through environmental cost recovery clause or fuel cost recovery clause (This order includes a list of all orders between 1985 and 2005); Order No. PSC-12-0498-PAA-EI, issued on September 27, 2012, in Docket No. 120153-EI, In re: Petition to recover capital costs of Polk Fuel Cost Reduction Project through the Fuel Cost Recovery Clause, by Tampa Electric Company; Order No. PSC-13-0505-PAA-EI, issued on October 28, 2013, in Docket No. 130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; Order No. PSC-14-0309-PAA-EI, issued on June 12, 2014, in Docket No. 140032-EI, In re: Petition to recover capital costs of Big Bend fuel cost reduction project through the fuel cost recovery clause, by Tampa Electric Company; Order No. PSC-15-0038-FOF-EI, issued on January 12, 2015, in Docket No. 150001-EI, In re: Fuel purchased power cost recovery clause with generating performance incentive factor.

approved by this Commission in Order No. PSC-14-0517-S-EI, issued on September 29, 2014, (Order No. PSC-14-0517)[12] prohibits the recovery of costs associated with the FPL interconnection through the fuel clause.

Section I, Term, of the settlement agreement prohibits FPUC from increasing its base rates during the minimum term of the agreement, or until after December 31, 2016. The settlement agreement also states in Section VI, Other Cost Recovery, as follows:

> Nothing in this agreement shall preclude the Company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges or (b) incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this settlement. Except as provided in this Agreement, it is the intent of the Parties in this Paragraph VI that FPUC not be allowed to recover through cost recovery clauses increases in the magnitude of costs, incurred after implementation of the new base rates, of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been traditionally and historically recovered through FPUC's base rates.

Additionally, FPUC has included actual and estimated consulting and legal fees in its fuel costs for 2014, 2015, and 2016. Actual costs included in its 2014 true-up calculation are $122,933. FPUC included $111,135 in its 2015 estimated/actual costs, and $387,000 its 2016 projected costs.

FPUC believes that costs incurred and projected to be incurred for the FPL interconnection and contracted consultants and legal services are directly fuel-related and will ultimately produce fuel savings that will flow to FPUC's customers through the fuel adjustment clause, and thus, are appropriate for recovery through the fuel cost recovery clause. FPUC argued that this Commission has clearly stated that the purpose of the clause proceedings is to provide for recovery of volatile costs that tend to fluctuate between rate case proceedings, which if incorporated in base rates, would unduly penalize the utility or its customers.[13]

No party filed testimony in the proceeding in opposition to FPUC's requested legal and consulting fees. In support of its request, FPUC witness Young argued that the consultants hired by FPUC engaged in activities related to the negotiation of a new power purchased contract with Eight Flags Energy, modification of FPUC's existing agreement with Rayonier Performance Fibers, and analysis of FPUC's current power purchase agreement to determine opportunities to produce fuel cost reductions. FPUC witness Cutshaw emphasized that the costs being requested are not associated with administrative functions associated with fuel procurement, nor associated

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[12] Order No. PSC-14-0517-S-EI, issued on September 29, 2014, in Docket No. 140025-EI, <u>In re: Application for rate increase by Florida Public Utilities Company</u>.

[13] Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, at p.37, <u>In Re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.</u>

with the Company's internal staff responsible for fuel procurement. FPUC witness Young stated that the costs FPUC is seeking to recover are similar to costs we have traditionally and historically allowed to be recovered through the fuel clause. In addition, witness Young pointed out that the costs requested have not been included in FPUC's base rates as these costs are volatile and fluctuate between rate case proceedings.

FPUC argued that it has met its burden of proof by demonstrating that the legal and consulting fees it proposes for recovery through the fuel clause are: (1) prudent expenses associated with retaining outside expertise that the Company does not otherwise have in-house; (2) work for which these consultants were retained are associated with projects that are either currently producing fuel savings or are reasonably expected to produce savings for the Company and its customers; and (3) expenses of a type that we have traditionally allowed FPUC to recover through the fuel adjustment clause.

OPC argued that the settlement agreement precludes FPUC from seeking recovery in the fuel clause of its legal and consulting fees as does Order No. 14546. It is OPC's position that FPUC is barred from seeking recovery in the fuel clause for the cost of types or categories that have traditionally and historically been recovered through FPUC's base rates. In addition, OPC argued that the base rate freeze provision in the settlement agreement also prohibits FPUC from recovering these costs through cost recovery clauses.

OPC contended that consulting and legal generation-related costs have traditionally and historically been recovered through base rates for both FPUC and other electric utilities. OPC acknowledged that FPUC was allowed recovery through the fuel clause of its legal and consulting fees associated with the issuance and evaluation of RFPs for purchased power agreements.[14] However, it is OPC's contention that generic legal and consulting activities have not been specifically identified and allowed to be recovered through the fuel clause.

In addition, OPC argued that Order No. 14546 sets forth the policy that costs permitted for recovery through the fuel clause must produce fuel savings contemporaneous with cost recovery. OPC asserted that FPUC is merely speculating that the consulting and legal activities for which it is seeking recovery in 2015 and 2016 will actually result in lower purchased power costs. While FPUC witness Young testified that some of the consultant and legal activities "produced" savings, OPC argued that he could identify no specific savings that were achieved as a result of those activities. OPC also maintained that FPUC conceded that the outside consulting and legal fees are fuel procurement and administration charges or costs that Order No. 14546 specifically precludes from recovery through the fuel clause

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[14] Order No. PSC-05-1252-FOF-EI (Order No. 05-1252), issued in December 23, 2005, in Docket No. 050001-EI, <u>In re: Fuel and purchased power cost recovery clause with generating performance incentive factor</u>.

Our basic guidelines for recovery of costs through the fuel adjustment clause are found in Order No. 14546.[15] In Order No. 14546 the parties stipulated to, and we approved, two basic principles for recovery of expenses through the fuel clause:

> 1. When similar circumstances exist, the Commission should attempt to treat, for cost recovery purposes, specific types of fossil fuel-related expenses in a uniform manner among the various electric utilities. At times, however, it may be appropriate to treat similar types of expenses in dissimilar ways.
>
> 2. Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause. The volatility of fossil fuel-related costs may be due to a number of factors including, but not necessarily limited to: price, quantity, number of deliveries, and distance. Except as noted below, these volatile fossil fuel-related charges are incurred by the utility for goods obtained or services provided prior to the delivery of fuel to the electric utility's dedicated storage facilities. (Dedicated storage facilities mean storage facilities which are used solely to serve the affected electric utility.) All other fossil fuel-related costs should be recovered through base rates.[16]

In addition, the parties recommended that the policy be flexible so that costs normally recovered through base rates could be recovered through the fuel adjustment clause where the utility took advantage of a cost-effective transaction and those costs were not recognized or anticipated in the level of costs used to establish the utility's base rates. In those instances, "[t]he Commission shall rule on the appropriate method of cost recovery based upon the merits of each individual case."[17] Order No. 14546 was intended to identify costs that were appropriate for cost recovery yet recognize that we retain the ability in individual cases to rule on the method of cost recovery.

As the starting point of our analysis, we disagree with OPC that FPUC has not "traditionally and historically" recovered consulting and legal fees through the fuel clause. In Docket Nos. 060001-EI, 070001-EI, 080001-EI, 090001-EI, 10001-EI, 110001-EI, 120001-EI, 130001-EI, and 140001-EI, legal and consulting fees associated with fuel-related work were included in FPUC's true-up filings which we approved without objection. Further, in Order No. PSC-05-1252, we approved the recovery of fees for Christensen and Associates related to the preparation and evaluation of a RFP for purchased power for its Northwest Division. In Order No. PSC-05-1252, we cited the fact that FPUC was a small, non-generating, investor-owned electric utility that did not have the resources internally to prepare an RFP and evaluate responses.[18] Because FPUC has "traditionally and historically" recovered these types of costs through the fuel clause, we find that the terms of the settlement agreement do not apply and do not prohibit recovery through the fuel clause at this time.

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[15] Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI,-B, In re: Cost Recovery Methods for Fuel-Related Expenses.
[16] Id. at p.2.
[17] Id. at p. 3.
[18] Order No. PSC-05-1252-FOF-EI, issued December 23, 2005, in Docket No. 050001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

FPUC has been aggressively seeking opportunities to reduce fuel costs to its consumers. To properly and thoroughly explore fuel-saving opportunities, FPUC engages legal and consulting assistance as it continues to lack in-house expertise. The costs that FPUC is requesting to be recovered in this proceeding are associated with legal and consulting fees incurred in the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier.

In 2016, FPUC will begin discussions with various purchased power providers in preparation for the 2017 expiration of its Northeast Division wholesale power contract with JEA. FPUC is presently reliant upon JEA for all its power needs in its Northeast Division and is prohibited from taking power from another wholesale power provider until the expiration of its wholesale power purchase agreement in December 2016. In order to obtain the lowest price and most favorable terms in its wholesale power contract to serve its Northeast Division, FPUC needs significant research, analysis, and negotiation unavailable in-house. These consulting and legal fees are not currently being recovered in FPUC's base rates. Nor were these fees anticipated in FPUC's last rate case, as these types of costs fluctuate significantly from year to year.

We find that there is no compelling reason to deviate from our past decisions. FPUC remains a small, non-generating electric utility lacking the in-house expertise to find and evaluate potential opportunities for fuel savings and craft and evaluate requests for proposals for generation needs. These costs were not included in its last rate case. At the time of its last rate case, similar costs were being recovered through the fuel clause. The costs FPUC is requesting for recovery through the fuel clause are not related to FPUC's internal staff for routine fuel and purchased power procurement and administration. FPUC projects that the opportunities being evaluated by its contracted consultants and legal professionals will result in fuel savings.

All parties agree that the proposed interconnection with FPL will result in improved system reliability for Amelia Island. Nor is there disagreement that interconnection with FPL will offer wholesale power purchase options not currently available to FPUC when its wholesale power agreement with JEA expires in December 2016. The disagreement rests with OPC's conclusion that Order No. 14546 prohibits cost recovery until cost savings are received by ratepayers. We do not read Order No. 14546 that restrictively.

Therefore, we find that the interconnection with FPL and the consulting and legal fees associated with the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier shall be recovered through the fuel cost recovery clause. Further, as agreed to by FPUC at hearing, the consultant's costs for the preparation of Commission filings for the consolidation of FPUC's fuel divisions shall be removed from its requested costs included in its true-up and projected filings. In order to facilitate that adjustment, we direct FPUC to file revised true-up and projection schedules reflecting removal of the costs associated with the preparation of Commission filings within 20 days of our vote.

Final fuel true-up amounts

FPUC has removed $2,046 in expenses associated with consultant fees from its request for cost recovery of the final true-up amounts for the period January 2014 through December 2014. The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the Northeast and Northwest Divisions were consolidated. The appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is an under-recovery of $1,474,307.

FPUC has removed $4,532 in expenses from its request for cost recovery of the final true-up amounts for the period January 2015 through December 2015. The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the respective divisions were consolidated. The appropriate fuel adjustment actual/estimated true-up amount for the period January 2015 through December 2015 is properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate fuel adjustment actual/estimated true-up amount for the period January 2015 through December 2015 is an under-recovery of $107,841.

FPUC has removed $6,578 from its request for cost recovery of 2014 and 2015 true-up amounts. This amount is the sum of the expense amounts referenced above and properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate total fuel adjustment true-up amount to be collected from January 2016 through December 2016 is an under-recovery of $1,582,148.

Consistent with our decision including the FPL interconnection and legal and consulting fees, the appropriate projected total fuel and purchased power cost recovery amounts for FPUC for the period January 2016 through December 2016 is $67,488,997.

FPUC has removed expenses associated with the preparation of Commission filings from its request for cost recovery of 2014 and 2015 true-up amounts. Therefore, we find that the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2016 through December 2016 is $68,971,145.

Based on previous adjustments made we find that the appropriate levelized fuel cost recovery factor for FPUC for the period January 2016 through December 2016 is 6.692 cents per kilowatt hour.

Based on the previous adjustments made, we find that the appropriate fuel cost recovery factors for FPUC for each rate class/delivery voltage level class adjusted for line losses is as stated below:

Rate Schedule	Adjustment
RS	$0.10619
GS	$0.10169
GSD	$0.09709
GSLD	$0.09407
LS	$0.07211
Step rate for RS	
RS Sales	$0.10619
RS with less than 1,000 kWh/month	$0.10188
RS with more than 1,000 kWh/month	$0.11438

The appropriate adjusted Time of Use (TOU) and Interruptible rates for the Northwest Division are:

Time of Use/Interruptible

Rate Schedule	Adjustment On Peak	Adjustment Off Peak
RS	$0.18588	$0.06288
GS	$0.14169	$0.05169
GSD	$0.13709	$0.06459
GSLD	$0.15407	$0.06407
Interruptible	$0.07907	$0.09404

Effective Date

Per stipulation of the parties, the new factors shall be effective beginning with the first billing cycle for January 2016 through the last billing cycle for December 2016. The first billing cycle may start before January 1, 2016, and the last cycle may be read after December 31, 2016, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by us.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that the stipulations of the parties contained in the Notice of Stipulations filed on October 30, 2015, as modified by our bench decision, attached hereto as Attachment A, is incorporated into and made a part of this Order. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC., and Tampa Electric Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2016 through December 2016. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors set forth herein during the period January 2016 through December 2016. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Fuel and Purchased Power Cost Recovery Clause With Generating Performance Incentive Factor docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 23rd day of December, 2015.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

STIPULATIONS

ISSUE 2A: The Commission should approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in DEF's April 2015 and August 2015 hedging reports.

ISSUE 2C: No adjustments are needed to account for replacement costs associated with the July 2014 forced outage at the Hines plant.

ISSUE 3A: Yes, the Commission should approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in FPL's April 2015 and August 2015 hedging reports.

ISSUE 3C: The total gain in 2014 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, was $67,626,867. This amount should be shared between FPL and its customers, with FPL retaining $12,976,120.

ISSUE 3D: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2014 through December 2014 is $460,428.

ISSUE 3E: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2014 through December 2014 is $2,259,985.

ISSUE 3F: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2015 through December 2015 is $441,826.

ISSUE 3G: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2015 through December 2015 is $2,759,649.

ISSUE 3H: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016 is $473,512

ISSUE 3I: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016 is $1,498,826.

ISSUE 3J: This issue has been deferred until 2016 to allow FPL to continue negotiations for potential reimbursement of St. Lucie 2 replacement power costs associated with the extended refueling outage in 2014.

ISSUE 3N: The Commission should approve FPL's proposed generation base rate adjustment (GBRA) factor of 3.899 percent for the Port Everglades Energy Center (PEEC) expected to go in-service on June 1, 2016.

ISSUE 3O: This issue has been dropped with the understanding that any party may raise it again in the 2016 proceeding.

ISSUE 3P: FPL has properly reflected in the fuel and purchased power cost recovery clause the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 5A: The Commission should approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in Gulf's April 2015 and August 2015 hedging reports.

ISSUE 6A: The Commission should approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in TECO's April 2015 and August 2015 hedging reports.

ISSUE 6C: The appropriate amount of capital costs for the Big Bend fuel conversion project that TECO should be allowed to recover through the Fuel Clause for the period January 2015 through December 2015 is $3,744,426.

ISSUE 6D: The appropriate amount of capital costs for the Big Bend fuel conversion project that TECO should be allowed to recover through the Fuel Clause for the period January 2016 through December 2016 is $4,894,041.

ISSUE 6E: No adjustments are needed to account for replacement costs associated with the June 2015 forced outage at Big Bend Unit 2.

ISSUE 6F: The cost of the natural gas burned during the testing of natural gas as a co-fired fuel at Big Bend Station is appropriate for recovery.

ISSUE 7: The appropriate actual benchmark levels for calendar year 2015 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

Duke:	$1,739,843
Gulf:	$ 677,983
TECO:	$1,479,981
FPL:	Not applicable

ISSUE 8: The appropriate actual benchmark levels for calendar year 2016 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

Duke:	$2,704,668
Gulf:	$ 752,900
TECO:	$1,532,270
FPL:	Not applicable

ISSUE 9: The appropriate final fuel adjustment true-up amounts for the period January 2014 through December 2014 are as follows:

FPL:	$10,088,837 (over-recovery) refunded as part of mid-course correction approved by Order No. 15-0161-PCO-EI
Duke:	$11,604,966 (over-recovery)
Gulf:	$ 8,084,753 (over-recovery)
TECO:	$ 2,919,025 (under-recovery)

ISSUE 10: The appropriate fuel adjustment actual/estimated true-up amounts for the period of January 2015 through December 2015 are as follows:

FPL:	$66,818,243 under-recovery
Duke:	$67,126,064 over-recovery
Gulf:	$11,285,334 over-recovery
TECO:	$30,509,575 over-recovery

ISSUE 11: The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2016 through December 2016 are as follows:

FPL:	$66,818,243 to be collected (under-recovery)
Duke:	$78,731,032 to be refunded (over recovery)
Gulf:	$19,370,087 to be refunded (over-recovery)
TECO:	$27,590,550 to be refunded (over-recovery)

ISSUE 12: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 are as follows:

FPL:	$3,023,588,111, which excludes prior period true up amounts, revenue taxes, the GPIF reward or penalty, or FPL’s portion of the gains from its Incentive Mechanism.
Duke:	$1,480,800,063

Gulf:	$400,060,296, including prior period true up amounts and revenue taxes
TECO:	$668,014,513, which is adjusted by the jurisdictional separation factor, excluding the GPIF reward or penalty, and the revenue tax factor, but including the prior period true up amounts.

ISSUE 14A: FPL has properly reflected in its 2016 GPIF targets/ranges the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 17: The appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2014 through December 2014 for each investor-owned electric utility subject to the GPIF is as follows:

FPL:	$23,303,114 reward
DEF:	$8,613,797 penalty
Gulf:	$2,648,312 reward
TECO:	$1,258,600 reward

ISSUE 18: The appropriate GPIF targets/ranges for the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF are shown below:

GPIF Targets / Ranges for the period January 2016 through December 2016							
Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
FPL	Ft. Myers 2	90.3	92.8	2,696	7,344	7,190	6,035
	Martin 8	82.3	84.3	1,681	7,017	6,927	2,261
	Manatee 3	92.6	95.1	2,127	7,011	6,873	3,765
	St. Lucie 1	85.1	88.1	6,754	10,471	10,391	406
	St. Lucie 2	92.5	95.5	6,470	10,270	10,175	439
	Turkey Point 3	90.8	94.3	7,125	11,102	10,838	1,272
	Turkey Point 4	84.6	87.6	5,710	11,082	10,872	861
	Turkey Point 5	93.5	95.5	1,638	7,132	7,047	2,207
	West County 1	90.8	93.3	2,759	6,967	6,772	5,750
	West County 2	90.1	92.6	3,106	6,891	6,671	6,027
	West County 3	91.7	94.2	2,777	6,851	6,673	5,883
	Total			42,843			34,906

GPIF Targets / Ranges for the period January 2016 through December 2016

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
DEF	Bartow 4	88.6	91.0	1,471	7,427	6,984	13,149
	Crystal River 4	83.2	87.4	934	10,465	10,053	5,227
	Crystal River 5	94.6	97.1	1,031	10,345	9,851	7,392
	Hines 1	92.4	93.2	413	7,319	6,855	6,758
	Hines 2	57.6	69.4	5,403	7,343	6,931	2,987
	Hines 3	82.9	84.5	1,028	7,227	6,745	6,298
	Hines 4	85.0	85.5	250	6,983	6,634	4,880
	Total			10,530			46,692

GPIF Targets / Ranges for the period January 2016 through December 2016

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
GULF	Crist 6	95.7	97.0	25	10,760	10,437	838
	Crist 7	82.3	83.4	51	10,449	10,136	1,809
	Daniel 1	92.9	95.0	10	10,698	10,377	455
	Daniel 2	95.2	96.2	13	10,605	10,287	529
	Smith 3	83.2	84.1	12	6,874	6,668	2,312
	Total			111			5,943

GPIF Targets / Ranges for the period January 2016 through December 2016

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
TECO	Big Bend 1	78.7	82.0	383	10,683	10,473	1,399
	Big Bend 2	68.7	72.3	894	10,460	10,025	2,528
	Big Bend 3	76.6	79.5	649	10,654	10,441	1,337
	Big Bend 4	76.9	80.6	673	10,458	10,075	2,660
	Polk 1	81.5	83.7	154	10,191	9,837	1,320
	Bayside 1	76.1	78.2	836	7,232	6,967	2,912
	Bayside 2	83.1	84.9	1,711	7,484	7,267	2,816
	Total			5,299			14,971

ISSUE 19: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 are as follows:

FPL: $3,128,284,160, which includes prior period true up amounts, revenue taxes, the GPIF reward or penalty, or FPL's portion of the gains from its Incentive Mechanism.

Duke: $1,394,464,724

Gulf: $402,708,608, including prior period true up amounts and revenue taxes.

TECO: $715,605,063, which is adjusted by the jurisdictional separation factor. The amount is $689,768,483, when the GPIF reward or penalty, the revenue tax factor, and the prior period true up amounts are applied.

ISSUE 20: The appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2016 through December 2016 is 1.00072.

ISSUE 21: The appropriate levelized fuel cost recovery factors for the period January 2016 through December 2016 are as follows:

FPL: For FPL, the fuel factors shall be reduced as of the in-service date of Port Everglades Energy Center (PEEC) to reflect the projected jurisdictional fuel savings for PEEC. The following separate factors for January 2016 through May 2016 and for June 2016 through December 2016 are approved:

a) 2.898 cents/kWh for January 2016 through the day prior to the PEEC in-service date (projected to be May 31, 2016);

b) 2.837 cents/kWh from the PEEC in-service date (projected to be June 1, 2016) through December 2016.

Duke: 3.677 cents per kWh (adjusted for jurisdictional losses)

Gulf: 3.650 cents/kWh

TECO: The appropriate factor is 3.671 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage.

ISSUE 22: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown below:

FPL: The appropriate fuel cost recovery line loss multipliers are provided below:

GROUPS	RATE SCHEDULE	JANUARY - DECEMBER Fuel Recovery Loss Multiplier
A	RS-1 first 1,000 kWh	1.00313
A	RS-1 all additional kWh	1.00313
A	GS-1, SL-2, GSCU-1	1.00313
A-1	SL-1, OL-1, PL-1 (1)	1.00313
B	GSD-1	1.00305
C	GSLD-1, CS-1	1.00205
D	GSLD-2, CS-2, OS-2, MET	0.99278
E	GSLD-3, CS-3	0.96536
A	GST-1 On-Peak	1.00313
	GST-1 Off-Peak	1.00313
A	RTR-1 On-Peak	-
	RTR-1 Off-Peak	-
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	1.00305
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	1.00305
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	1.00205
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	1.00205
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	0.99349
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	0.99349
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	0.96536
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	0.96536
F	CILC-1(D), ISST-1(D) On-Peak	0.99234
	CILC-1(D), ISST-1(D) Off-Peak	0.99234

GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER Fuel Recovery Loss Multiplier
B	GSD(T)-1 On-Peak	1.00305
	GSD(T)-1 Off-Peak	1.00305
C	GSLD(T)-1 On-Peak	1.00205
	GSLD(T)-1 Off-Peak	1.00205
D	GSLD(T)-2 On-Peak	0.99349
	GSLD(T)-2 Off-Peak	0.99349

DEF:

Fuel Recovery Line Loss Multipliers		
Group	Delivery Voltage Level	Line Loss Multiplier
A	Transmission	0.9800
B	Distribution Primary	0.9900
C	Distribution Secondary	1.0000
D	Lighting Service	1.0000

FPUC: The appropriate line loss multiplier is 1.0000.

Gulf:

Fuel Recovery Line Loss Multipliers		
Group	Rate Schedules	Line Loss Multipliers
A	RS, RSVP, RSTOU, GS,GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00773
B	LP, LPT, SBS(2)	0.98353
C	PX, PXT, RTP, SBS(3)	0.96591
D	OSI/II	1.00777

(1) Includes SBS customers with a contract demand in the range of 100 to 499 kW
(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 kW
(3) Includes SBS customers with a contract demand over 7,499 kW

TECO:

Fuel Recovery Line Loss Multipliers	
Metering Voltage Schedule	Line Loss Multiplier
Distribution Secondary	1.0000
Distribution Primary	0.9900
Transmission	0.9800
Lighting Service	1.0000

ISSUE 23: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses is:

: FPL: The tables below (which also include the fuel recovery loss multiplier listed in the preceeding stipulation for Issue 22).

GROUPS	RATE SCHEDULE	JANUARY 2016 - MAY 2016		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.898	1.00313	2.580
A	RS-1 all additional kWh	2.898	1.00313	3.580
A	GS-1, SL-2, GSCU-1	2.898	1.00313	2.907
A-1	SL-1, OL-1, PL-1 (1)	2.679	1.00313	2.687
B	GSD-1	2.898	1.00305	2.907
C	GSLD-1, CS-1	2.898	1.00205	2.904
D	GSLD-2, CS-2, OS-2, MET	2.898	0.99278	2.877
E	GSLD-3, CS-3	2.898	0.96536	2.798
A	GST-1 On-Peak	4.037	1.00313	4.050
	GST-1 Off-Peak	2.420	1.00313	2.428
A	RTR-1 On-Peak	-	-	1.143
	RTR-1 Off-Peak	-	-	(0.479)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.037	1.00305	4.049
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.420	1.00305	2.427
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.037	1.00205	4.045
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.420	1.00205	2.425
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.037	0.99349	4.011
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.420	0.99349	2.404
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.037	0.96536	3.897
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.420	0.96536	2.336
F	CILC-1(D), ISST-1(D) On-Peak	4.037	0.99234	4.006
	CILC-1(D), ISST-1(D) Off-Peak	2.420	0.99234	2.401

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

:

ESTIMATED FOR THE PERIOD OF: JANUARY 2016 THROUGH MAY 2016

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	5.434	1.00305	5.451
	GSD(T)-1 Off-Peak	2.568	1.00305	2.576
C	GSLD(T)-1 On-Peak	5.434	1.00205	5.445
	GSLD(T)-1 Off-Peak	2.568	1.00205	2.573
D	GSLD(T)-2 On-Peak	5.434	0.99349	5.399
	GSLD(T)-2 Off-Peak	2.568	0.99349	2.551

GROUPS	RATE SCHEDULE	JUNE 2016 - DECEMBER 2016		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.837	1.00313	2.519
A	RS-1 all additional kWh	2.837	1.00313	3.519
A	GS-1, SL-2, GSCU-1	2.837	1.00313	2.846
A-1	SL-1, OL-1, PL-1 (1)	2.622	1.00313	2.630
B	GSD-1	2.837	1.00305	2.846
C	GSLD-1, CS-1	2.837	1.00205	2.843
D	GSLD-2, CS-2, OS-2, MET	2.837	0.99278	2.817
E	GSLD-3, CS-3	2.837	0.96536	2.739
A	GST-1 On-Peak	3.952	1.00313	3.964
	GST-1 Off-Peak	2.369	1.00313	2.376
A	RTR-1 On-Peak	-	-	1.118
	RTR-1 Off-Peak	-	-	(0.470)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.952	1.00305	3.964
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.369	1.00305	2.376
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.952	1.00205	3.960
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.369	1.00205	2.374
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.952	0.99349	3.926
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.369	0.99349	2.354
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.952	0.96536	3.815
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.369	0.96536	2.287
F	CILC-1(D), ISST-1(D) On-Peak	3.952	0.99234	3.922
	CILC-1(D), ISST-1(D) Off-Peak	2.369	0.99234	2.351

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

GROUPS	RATE SCHEDULE	JUNE 2016 - SEPTEMBER 2016		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	5.319	1.00305	5.335
	GSD(T)-1 Off-Peak	2.514	1.00305	2.522
C	GSLD(T)-1 On-Peak	5.319	1.00205	5.330
	GSLD(T)-1 Off-Peak	2.514	1.00205	2.519
D	GSLD(T)-2 On-Peak	5.319	0.99349	5.284
	GSLD(T)-2 Off-Peak	2.514	0.99349	2.498

DEF:

Fuel Cost Factors (cents/kWh) GSD-1, GSDT-1, SS-1, CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3, IS-1, IST-1, IS-2, IST-2, SS-2, LS-1						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	3.608	4.860	3.034
B	Distribution Primary	--	--	3.645	4.910	3.065
C	Distribution Secondary	--	--	3.682	4.960	3.097
D	Lighting Secondary	--	--	3.445	--	--

Fuel Cost Factors (cents/kWh) RS-1, RST-1, RSL-1, RSL-2, RSS-1						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
C	Distribution Secondary	3.353	4.353	3.634	4.895	3.056

Fuel Cost Factors (cents/kWh) GS-1, GST-1, GS-2						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	3.574	4.814	3.006
B	Distribution Primary	--	--	3.611	4.864	3.037
C	Distribution Secondary	--	--	3.647	4.913	3.067

Gulf:

Group	Rate Schedules*	Line Loss Multipliers	Fuel Cost Factors ¢/KWH		
			Standard	Time of Use	
				On-Peak	Off-Peak
A	RS, RSVP, RSTOU, GS,GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00773	3.678	4.494	3.342
B	LP, LPT, SBS(2)	0.98353	3.590	4.387	3.261
C	PX, PXT, RTP, SBS(3)	0.96591	3.526	4.308	3.203
D	OSI/II	1.00777	3.631	N/A	N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 kW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 kW will use the recovery factor applicable to Rate Schedule LP; and (3) customers with a contract demand over 7,499 kW will use the recovery factor applicable to Rate Schedule PX.

TECO:

Metering Voltage Level	Fuel Charge Factor (cents per kWh)	
Secondary	3.676	
RS Tier I (Up to 1,000 kWh)	3.361	
RS Tier II (Over 1,000 kWh)	4.361	
Distribution Primary	3.639	
Transmission	3.602	
Lighting Service	3.627	
Distribution Secondary	3.937	(on-peak)
	3.564	(off-peak)
Distribution Primary	3.898	(on-peak)
	3.528	(off-peak)
Transmission	3.858	(on-peak)
	3.493	(off-peak)

ISSUE 24A: Yes. For the Crystal River 3 Uprate project, the amount to be included is $56,510,403, which was approved by the Commission in a bench vote at Hearing on August 18, 2015. At Hearing, on August 18, 2015, the Commission approved

DEF's stipulation with the parties to leave the Levy portion of the NCRC charge at $0 for 2016 and 2017.

ISSUE 25A: As approved by the Commission at its October 19, 2015 Special Agenda Conference, FPL has included $34,249,614.

ISSUE 25B: The appropriate 2016 projected non-fuel revenue requirements for West County Energy Center Unit 3 (WCEC-3) to be recovered through the Capacity Clause is $145,515,209.

ISSUE 25C: FPL has properly reflected in the capacity cost recovery clause the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 28: The appropriate final capacity cost recovery true-up amounts for the period January 2014 through December 2014 are as follows:
Duke: $13,962,445 under-recovery.
Gulf: $893,047 under-recovery.
FPL: $2,951,171 under-recovery.
TECO: $140,386, over-recovery.

ISSUE 29: The appropriate final capacity cost recovery actual/estimated true-up amounts for the period January 2015 through December 2015 are as follows:
Duke: $24,680,810 under-recovery
Gulf: $910,906 over-recovery
FPL: $7,699,316 over-recovery
TECO: $2,063,383 over-recovery

ISSUE 30: The appropriate final capacity cost recovery true-up amounts to be collected/refunded during the period January 2016 through December 2016 are as follows:
Duke: $38,643,256, to be collected (under-recovery).
Gulf: $17,859, to be refunded (over-recovery).
FPL: $4,748,145, to be refunded (over-recovery).
TECO: $2,203,769, to be refunded (over-recovery).

ISSUE 31: The appropriate projected total capacity cost recovery amounts for the period January 2016 through December 2016 are as follows:

FPL: Jurisdictionalized, $321,148,426 for the period January 2016 through December 2016, excluding prior period true-ups, revenue taxes, nuclear cost recovery amount, and WCEC-3 jurisdictional non-fuel revenue requirements.

Duke: $358,842,970.

Gulf: $85,495,331.

TECO: $30,473,670.

ISSUE 32: The appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2016 through December 2016 are as follows:

FPL: The projected net purchased power capacity cost recovery amount to be recovered over the period January 2016 through December 2016 is $496,417,572, including prior period true-ups, revenue taxes, the nuclear cost recovery amount and WCEC-3 revenue requirements.

Duke: The appropriate projected net purchased power capacity cost recovery amount, excluding nuclear cost recovery, is $397,772,416. The appropriate nuclear cost recovery amount is that which is approved in Issue 24A.

Gulf: $85,539,016 including prior period true-up amounts and revenue taxes.

TECO: The total recoverable capacity cost recovery amount to be collected, including the true-up amount and adjusted for the revenue tax factor, is $28,290,255.

ISSUE 33: The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2016 through December 2016 are as follows:

FPL: The appropriate jurisdictional separation factors are:

FPSC	94.67506%
FERC	5.32494%

Duke: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%, consistent with the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI.

Gulf: 97.07146%.

TECO: The appropriate jurisdictional separation factor is 1.0000000.

ISSUE 34: The appropriate capacity cost recovery factors for the period January 2016 through December 2016 are shown below:

FPL: See the table on the next page.

ESTIMATED FOR THE PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2016 - Dec 2016 Capacity Recovery Factor				2016 WCEC-3 Capacity Recovery Factor				Total Jan 2016 - Dec 2016 Capacity Recovery Factor			
	($/KW)	($/kwh)	RDC ($/KW) (1)	SDD ($/KW) (2)	($/KW)	($/kwh)	RDC ($/KW)	SDD ($/KW)	($/KW)	($/kwh)	RDC ($/KW) (1)	SDD ($/KW) (2)
RS1/RTR1	-	0.00348	-	-	-	0.00140	-	-	-	0.00488	-	-
GS1/GST1	-	0.00326	-	-	-	0.00140	-	-	-	0.00466	-	-
GSD1/GSDT1/HLFT1	1.09	-	-	-	0.46	-	-	-	1.55	-	-	-
OS2	-	0.00240	-	-	-	0.00126	-	-	-	0.00366	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.22	-	-	-	0.56	-	-	-	1.78	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.19	-	-	-	0.51	-	-	-	1.70	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.22	-	-	-	0.66	-	-	-	1.88	-	-	-
SST1T	-	-	$0.15	$0.07	-	-	$0.06	$0.03	-	-	$0.21	$0.10
SST1D1/SST1D2/SST1D3	-	-	$0.15	$0.07	-	-	$0.06	$0.03	-	-	$0.22	$0.10
CILC D/CILC G	1.35	-	-	-	0.63	-	-	-	1.98	-	-	-
CILC T	1.28	-	-	-	0.55	-	-	-	1.83	-	-	-
MET	1.38	-	-	-	0.66	-	-	-	2.04	-	-	-
OL1/SL1/PL1	-	0.00059	-	-	-	0.00036	-	-	-	0.00095	-	-
SL2, GSCU1	-	0.00225	-	-	-	0.00064	-	-	-	0.00289	-	-

Duke:

Rate Class		Capacity Cost Recovery Factor	
		Cents / kWh	Dollars / kW-month
Residential		1.418	
General Service Non-Demand		1.100	
	At Primary Voltage	1.089	
	At Transmission Voltage	1.078	
General Service 100% Load Factor		0.779	
General Service Demand			3.94
	At Primary Voltage		3.90
	At Transmission Voltage		3.86
Curtailable			2.32
	At Primary Voltage		2.30
	At Transmission Voltage		2.27
Interruptible			3.14
	At Primary Voltage		3.11
	At Transmission Voltage		3.08
Standby Monthly			0.383
	At Primary Voltage		0.379
	At Transmission Voltage		0.375
Standby Daily			0.182
	At Primary Voltage		0.180
	At Transmission Voltage		0.178
Lighting		0.217 (cents/kWh)	

Gulf:

Rate Class	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW-month
RS, RSVP, RSTOU	0.919	
GS	0.812	
GSD, GSDT, GSTOU	0.705	
LP, LPT		2.98
PX, PXT, RTP, SBS	0.581	
OS-I/II	0.123	
OSIII	0.544	

TECO:

Rate Class and Metering Voltage	**Capacity Cost Recovery Factor**	
	Cents / kWh	Dollars / kW
RS Secondary	0.178	
GS and TS Secondary	0.166	
GSD, SBF Standard		
Secondary		0.530
Primary		0.520
Transmission		0.520
GSD Optional		
Secondary	0.123	
Primary	0.122	
IS, SBI		
Primary		0.430
Transmission		0.420
LS1 Secondary	0.021	

ISSUE 35: The new factors should be effective begin with the first billing cycle for January 2016 through the last billing cycle for December 2016. The first billing cycle may start before January 1, 2016, and the last cycle may be read after December 31, 2016, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

ISSUE 36: Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct staff to verify that the revised tariffs are consistent with the Commission's decision.

ISSUE 37: This docket is an on-going docket and should remain open.